## 7.0. TRADITIONAL ELECTRIC INDUSTRY REGULATORY SYSTEM AND EFFECT ON ALLOCATION OF INVESTMENT RISK OF NEW IGCC PLANTS.

### 7.1. Description of traditional electric industry regulatory system.

What follows is a summary description of the traditional approach to regulation of the electric industry. While the structure of the electric industry has become more complicated with, inter alia, the increased role of merchant generators, most, but not all states, continue to use a more traditional approach to regulating the electric industry. However, in some states and in varying degrees, the electric industry has been significantly restructured, and competition has been introduced for retail electricity generation and sales. Section 8.0 below discusses in detail the regulatory systems in five example states, three with more traditional regulatory systems and two with retail competition. Included in that discussion are detailed citations to statutes and administrative and judicial decisions that support the more summary discussion in this Section 7.0. The purpose of discussing traditional and competitive regulatory systems is to develop an understanding of the effect that they have on the allocation of electricity-generation investment risk between investors and ratepayers and to examine the legal authority and precedents for allocating such risk.

7.11. Treatment of Companies as Natural Monopolies.

The business of generating, transmitting, and distributing electricity to the public has traditionally been regarded as a natural monopoly. Generation, transmission, and distribution were believed to be most efficiently provided by a single company that was the sole provider of these services for the public in an assigned geographic area. See Transmission Access Policy Study Group v. Federal Energy Regulatory Commission, 225 F.3d 667, 681 (D.C. Cir. 2000), aff'd sub nom. New York v. Federal Energy Regulatory Commission, 535 U.S. 1 (2002).

Under this approach, a state grants a single company the exclusive right to sell and distribute electricity to consumers in a specified service area and requires that company to undertake the obligation to meet the electricity needs of all such consumers, including both existing and future consumers. The corporate structure of the company can vary. One possible structure is a single corporation handling all of these activities for a given service area. Another possible structure is a parent (or holding) company with subsidiary operating companies, each of which handles generation, transmission, and distribution within a particular service area generally in a specific state.

In light of the utility's exclusive right and obligation to meet consumers' electricity needs in the service area, the state generally regulates (through a state PUC) the generation, retail sale, and distribution of electricity by the utility. Such regulation encompasses setting of electric rates and may also include authorization to construct facilities. Rural

electric cooperatives (most of which are nonprofit cooperatives financed through the Rural Utilities Service of the U.S. Department of Agriculture under the Rural Electrification Act) and municipal utilities are also generally given the exclusive right and obligation to meet consumers' electricity needs in their respective service areas. In general, the municipality (rather than the state PUC) has jurisdiction over the rates for municipal utilities. Rural electric cooperatives may or may not be under state PUC jurisdiction. See Arkansas Electric Cooperative, Corp. v. Arkansas Public Service Commission, 461 U.S. 375 (1983) (upholding jurisdiction asserted by state PUC over rates, for wholesale sales to cooperative members (as well as for retail sales to consumers), of rural electric generation cooperative with federal financing).

In contrast with the regulation of generation, retail sale, and distribution of electricity at the state or local level, transmission of electricity, and sale of electricity for resale, in interstate commerce are regulated at the federal level under the Federal Power Act (16 U.S.C. 791a-828e) by the FERC.[158] Transmission Access Policy Study Group, 225 F.3d at 690-96 (describing FERC jurisdiction over transmission and wholesale sales in interstate commerce and upholding FERC's jurisdiction over unbundled retail transmission and use of multifactor test to distinguish transmission from distribution facilities); see also Northern States Power v. Federal Energy Regulatory Commission, 176 F.3d 1090 (8th Cir. 1999), cert. den., 528 U.S. 1182 (2000). (holding that FERC exceeded its jurisdiction in requiring utility to curtail provision of electricity to its retail and its wholesale customers on the same pro rata basis). For example, where one company purchases electricity from another company generating the electricity and in turn sells the purchased electricity to retail customers, the initial purchase for resale is generally subject to FERC jurisdiction, including rate review. See Federal Power Commission v. Florida Power & Lighting Co., 404 U.S. 453 (1972) (upholding FERC jurisdiction over utility generating electricity sold in same state because utility is connected with interstate transmission system). However, because the transmission and distribution system in the portion of Texas in the Electric Reliability Council of Texas (ERCOT) region of the North American Electric Reliability Council (NERC) has very limited interconnections with transmission and distribution systems in contiguous states, the FERC lacks jurisdiction over transmission and sales for resale in that portion of Texas. See City Public Service Board of San Antonio v. Public Utility Commission of

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[158] In exercising its jurisdiction over sales for resale, the FERC requires public utilities making such sales to charge just and reasonable rates, which may be either cost-based rates or market-based rates (i.e., rates reflecting prices in a competitive electricity market when such a market is shown to exist). See Section 9.5 below. In exercising its jurisdiction over interstate transmission, the FERC generally requires public utilities that own, control, or operate facilities used for transmitting electricity in interstate commerce to file open-access, nondiscriminatory transmission tariffs. See Order No. 888, 61 Fed Reg. 21,540 (1996), clarified, 76 FERC ¶ 61,009 and 76 FERC ¶61,347 (1999), on reh'g, Order No. 888-A, 62 Fed. Reg.12274 (1997), clarified, 79 FERC ¶ 61,182 (1997), on reh'g, Order No. 888-B, 62 Fed. Reg. 64688 (1997), on reh'g, Order No. 888-C, 82 FERC ¶ 61,046 (1998), aff'd in relevant part sub nom. Transmission Access Policy Study Group, 225 F.3d 667.

Texas, 9 S.W.3d 868, 875 n.15 (Tex. App. 2000), aff'd , 53 S.W.3d 310 (Tex. Sup. Ct. 2001).[159]

Sales for resale and transmission by rural electric cooperatives with federal financing and by municipal utilities are not subject to FERC jurisdiction. Salt River Project Agricultural Improvement and Power District v. Federal Power Commission, 391 F.2d 470 (D.C. Cir. 1968). However, the exception from FERC jurisdiction for rural electric cooperatives does not apply once they are no longer using federal financing. Golden Spread Electric Cooperative, 39 FERC ¶ 61,322 (1987), reh'g den., 40 FERC ¶ 61,348 (1987).

FERC jurisdiction over sales for resale in interstate commerce includes review of wholesale sale rates. In order to approve or set wholesale rates, the FERC must find them to be "just and reasonable." See 16 U.S.C. 824d(b) and 824e(a). Further, under the Supremacy Clause of the U.S. Constitution (art. VI, clause 2), the FERC's rate jurisdiction over sales for resale in interstate commerce is exclusive and pre-empts review by state PUCs or other state or local ratemaking authorities of the justness and reasonableness of wholesale rates. See, e.g., Nantahala Power & Light Co. v. Thornburg, 476 U.S. 953, 963-66 (1986); and Sinclair Machines Products, Inc., 498 A.2d 696, 698-705 (N.H. 1985) (holding state PUC is pre-empted from denying pass-through of FERC-approved costs of cancelled nuclear plant despite state statutory bar against recovery of capital costs on construction work in progress).

Moreover, federal pre-emption is not limited to the wholesale rates themselves. Generally, matters on which the FERC makes justness and reasonableness determinations while exercising its jurisdiction over wholesale sales cannot be revisited by the state PUC in a way that results in denying pass-through (i.e., in trapping) of costs that are under FERC jurisdiction and that the FERC determines are just and reasonable. As part of its wholesale-sales jurisdiction, the FERC has the authority to review any inter-company agreement that "significantly *affects*" wholesale sales. Mississippi Industries v. Federal Energy Regulatory Commission, 808 F.2d 1527, 1542 (D.C. Cir. 1987). Consequently, a state PUC is pre-empted from finding unjust or unreasonable any costs reflected in wholesale rates, or based on inter-company agreements, approved by the FERC and from denying pass-through of these costs by wholesale purchasers to their retail customers based on such a finding.

For example, where the FERC reviewed an inter-company agreement that allocated quantities of low-cost hydroelectric power, generated and provided by a third party, between two purchasing affiliated companies, the FERC found the allocations were unfair and ordered different allocations. One of the affiliated companies made sales to its parent industrial company, while the second of the affiliated companies had retail and wholesale customers. The U.S. Supreme Court held that the state PUC had to set the

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[159] For similar reasons, the FERC lacks jurisdiction over transmission and wholesale sales in Alaska and Hawaii. See New York, 535 U.S. at 7. These two states are not further discussed in this paper.

second affiliated company's retail rates based on the FERC-determined allocations, not on different allocations that would assume a greater share of low-cost power (and thus lower power costs) for retail sales. Nantahala Power & Light, 476 U.S. at 969. The state PUC lacked the authority to assume a greater low-cost-power allocation for retail sales because that would effectively attribute a lower amount of power costs to retail sales and thereby prevent pass-through of (i.e., trap) a portion of the power costs that the FERC had approved for the affiliated companies. Id. at 970-72.

Similarly, where, after reviewing an inter-company agreement that allocated quantities of high-cost nuclear power among the operating companies in a holding company, the FERC required different allocations and set wholesale rates for the power, the allocations and rates were binding on a state PUC with jurisdiction over one of the operating companies. Mississippi Power & Light Co. v. Mississippi ex rel. Moore, 487 U.S. 354, 372-77 (1988). In making those determinations, the FERC did not made an express finding on the prudence of the inter-company agreement or the investment in the nuclear plant because the issues, while integral to the FERC's review, were not raised. Id. at 368. The state PUC was still pre-empted from considering such prudence for the purpose of trapping the FERC-approved costs and had to allow pass-through of the nuclear plant costs resulting from the quantity of high-cost power and the rates determined by the FERC. Id. at 372-73.

However, this does not mean that state PUC rate review is entirely pre-empted in all circumstances. While the state PUC must treat, as just and reasonable, the FERC-approved wholesale rates charged by the wholesale seller, the state PUC has the authority to review the quantity of electricity contracted for or purchased at those rates by the wholesale purchaser, unless a FERC-approved agreement obligates the wholesale purchaser concerning the quantity as well as the price. For example, in Pike County Light and Power Co. v. Pennsylvania Public Utility Commission, 465 A.2d 735, 737-38 (Pa. Commw. 1983), the Court held that the state PUC could not review the wholesale rates paid for electricity resold to retail customers, but could review whether and how much electricity was prudently purchased by the wholesale purchaser and determine what amount of costs could be passed through to retail customers. Because the FERC had approved the rates, but not any particular quantity of electricity, for the sale for resale, the state PUC could consider the wholesale purchaser's alternative sources for electricity to determine what quantity was prudently purchased in the particular sale for resale. Id. at 738. Similarly, in Gulf States Utilities Co. v. Public Utility Commission of Texas, 841 S.W.2d 459, 468-71 (Tex. App. 1992), it was held that the state PUC could review a utility's prudence in entering into a wholesale purchase agreement where the utility was not otherwise obligated (e.g., under an integrated pooling agreement) to purchase the power. See also Pennsylvania Power Co. v. Pennsylvania Public Utility Commission, 561 A.2d 43, 49-53 (Pa. Commw. 1989), aff'd, 587 A.2d 312 (Pa. 1991), cert. den., 502 U.S. 821 (1991); Kentucky West Virginia Gas Co. v. Pennsylvania Public Utility Commission,

837 F.2d 600, 605-16 (3d Cir. 1988), cert. den., 488 U.S. 941 (1988); and Sinclair Machines Products, 498 A.2d at 705.

Moreover, even where a utility is obligated under a FERC-approved agreement to purchase power (i.e., capacity in a nuclear plant) so that the state PUC cannot review the prudence of the purchase, the state PUC may review the utility's prudence in retaining, rather than selling, its share of such capacity. New Orleans Public Service, Inc. v. Council of City of New Orleans, 491 U.S. 350 (1989); and New Orleans Public Service, Inc. v. Council of City of New Orleans, 911 F.2d 993, 1001-04 (5th Cir. 1990).

In summary, the scope of state PUC review is much more limited for pass-through to retail customers of plant costs reflected in the wholesale rates of the plant owner or in inter-company agreements than for direct recovery from retail customers of plant costs reflected in the retail rates of the plant owner. Yet, some prudence issues remain within the purview of the state PUC. In addition, even when the state PUC must allow eventual pass-through of FERC-approved costs to retail customers, the state PUC may apply normal rate procedures even if they result in delaying that pass-through (e.g., through suspension of proposed rate increases) and do not allow the utility to recover interest during the delay period. Arkansas Power & Light Co. v. Missouri Public Service Commission, 829 F.2d 1444, 1452-53 (8th Cir. 1987). Similarly, the state PUC may exercise its discretion to require pass-through in a general rate case or other procedure that results in delayed cost recovery, rather than in an adjustment clause. See, e.g., Kentucky West Virginia Gas Co. v. Pennsylvania Public Utility Commission, 862 F.2d 69, 73-74 (3d Cir. 1988); Public Service Co. of Colorado v. Public Utilities Commission of Colorado, 644 P.2d 933, 940-42 (Colo. 1982); and Narragansett Electric Co. v. Burke, 381 A.2d 1358, 1362-63 (R.I. 1977), cert. den., 435 U.S. 972 (1978). However, where, under state statute, a state PUC only has discretion to deny pass-through in an adjustment clause if the costs are unreasonable, the state PUC cannot deny or delay pass-through of FERC-approved costs. See Eastern Edison Co. v. Department of Public Utilities, 446 N.E.2d 684, 689-90 (Mass. 1973).

7.12. Just and reasonable rates.

Utility regulatory commissions (whether federal or state) are generally required by statute, as interpreted by the courts, to set rates for a utility that are "just and reasonable." The U.S. Supreme Court explained this requirement as follows:

> [T] he fixing of 'just and reasonable' rates [ ] involves a balancing of the investor and consumer interests...[T]he investor interest has a legitimate concern with the financial integrity of the company whose rates are being regulated. From the investor or company point of view it is important that there be enough revenue not only for operating expenses but also for the capital costs of the business...[T]he return to the equity owner should be commensurate with returns on investments in other enterprises having corresponding risks. That return, moreover, should be sufficient to assure confidence in the financial integrity of the enterprise, so as to

> maintain its credit and to attract capital. Federal Power Commission v. Hope Natural Gas Co. (FPC v. Hope), 320 U.S. 591, 603 (1944).

See also Bluefield Water Works & Improvement Co. v. Public Service Commission of West Virginia, 262 U.S. 679, 692 (1923) (holding that rates must permit a public utility to "earn a return on the value of the property which it employs for the convenience of the public equal to that generally being made at the same time and in the same general part of the country on investments in other business undertakings which are attended by corresponding risks and uncertainties"); and Duquesne Light Co. v. Barasch, 488 U.S. 299, 315-16 (1989) (explaining that "just and reasonable" rates must balance the interests of investors and consumers). This requirement for "just and reasonable" rates is generally grounded in the federal constitutional bar against confiscatory taking of private property. See id. at 307-08.

Aside from this general standard, utility regulatory commissions are "not bound to the use of any single formula or combination of formulae in determining rates...[I]t is the result reached not the method employed which is controlling." FPC v. Hope, 320 U.S. at 602. Moreover, due to the economic complexity of the ratemaking process, there is no single "just and reasonable" rate. Instead, there is a "zone of reasonableness" within which the rate must be set. Federal Power Commission v. Conway Corp., 426 U.S. 271, 278 (1976); see also Permian Basin Area Rate Cases, 390 U.S. 747, 770 (1968) and Montana-Dakota Co. v. Northwestern Public Service Co., 341 U.S. 246, 251 (1951).

This emphasis by the U.S. Supreme Court on "end results" changed the focus of the ratemaking process. For example, before FPC v. Hope, much attention was paid to whether the property on which investors would receive a return should be valued at the original cost or the reproduction cost of property. See, e.g., Smyth v. Ames, 169 U.S. 469, 546 (1898) (requiring receipt of "fair value" of the property); McCardle v. Indianapolis Water Co., 272 U.S. 402, 411-12 (1925) (requiring receipt of fair return on reproduction costs of property); Missouri ex rel. Southwestern Bell Telephone Co. v. Public Service Commission of Missouri, 262 U.S. 276, 306-07 (1923) (dissenting opinion suggesting requirement of fair return on prudent investment); and Duquesne Light, 488 U.S. at 308-10 (explaining effect of FPC v. Hope on ratemaking process). After FPC v. Hope, none of these specific approaches was constitutionally required, and, in fact, some utility regulatory commissions consider multiple approaches to property valuation in setting just and reasonable rates.

### 7.13. Cost-based ratemaking.

In setting just and reasonable rates under traditional utility regulation, utility regulatory commissions apply a cost-of-service analysis. Under this approach, rates are set to allow the utility to earn total revenues sufficient to cover the cost of service approved by the utility regulatory commission. The cost of service includes: return of (through depreciation and amortization) and return on the utility's capital investment (i.e., the utility's "rate base") related to electric service; and the utility's operating expenses

related to such service. For purposes of establishing the cost of service, the utility regulatory commission initially selects a representative test period, often including the twelve months just before initiation of the rate review. See NEPCO Municipal Rate Committee v. FERC, 668 F.2d 1327, 1338 (D.C. Cir. 1981), cert. den., 457 U.S. 1117 (1982) (discussing use of two test periods, i.e., the most recent 12 months and the subsequent projected 12 months). The levels of capital investment, cost of capital (except return on equity, for which the most current data are generally used), and operating expenses in the test period are evaluated by the utility regulatory commission and provide a starting point for determining what levels should be included in the cost of service and covered by the rates. The levels in the test period may be adjusted to the extent that they are determined to be unrepresentative of the future (e.g., are unlikely to continue) or to be unreasonable. See Paul Rodgers and Charles D. Gray, "State Commission Treatment of Nuclear Plant Cancellation Costs," 13 Hofstra L. Rev. 443, 447-49 (Spring 1985) (generally describing cost-based ratemaking process).

*Costs related to capital.*

Specifically, with regard to capital investments, the utility regulatory commission determines which investments should be included in the rate base and in what dollar amounts. In general, investments are included in the rate base to the extent that they were prudent at the time that they were made and are used and useful (i.e., actually used and not superfluous) in providing electric service. See Jonathan A. Lesser, "The Used and Useful Test: Implications for a Restructured Electric Industry," 23 Energy L. J. 349, 352 (2002).

However, the extent to which investments were prudent when made and to which they turned out to be used and useful in providing electric service may not be coincident. For example, while a utility might prudently decide to invest in a new electricity generating plant based on then-current projections of electricity demand and planning and construction costs, the plant might be cancelled before completion because of changes in projected or actual demand or construction costs. Depending on, inter alia, the applicable underlying statutory authority for setting rates, utility regulatory commissions take various approaches to addressing plant cancellations.

One approach (the "prudent investment" approach) is to include, in rate base, electricity generating plant investments that were prudent when made, regardless of whether the plant is ultimately completed and used. See William J. Baumol and J. Gregory Sidak, "The Pig in the Python: Is Lumpy Capacity Investment Used and Useful?", 23 Energy L. J. 383, 391-93 (2002). Review to determine whether an investment was prudent is generally conducted after plant construction is completed or terminated and may encompass an entire series of utility decisions, including the initial decision to build, decisions during design and construction, and decisions to delay or terminate construction. Nevertheless, the determination of prudence is based on the information that was known or reasonably should have been known at the time the particular decision

was made. See Richard D. Gary and Edgar M. Roach, Jr. "the Proper Regulatory Treatment of Investment in Cancelled Nuclear Plants," 13 Hofstra L. Rev. 469, 472-84 (Spring 1985). To the extent the investment is found to be prudent and is included in rate base, the plant owner is allowed to recover both his investment and return on the investment. At least with regard to cancelled nuclear plants, utility regulatory commissions have not frequently used the "prudent investment" approach and thereby allowed recovery of both return on and return of capital. See Rodgers and Gray, 13 Hofstra L. Rev. at 452-53; and David P. Barker, "Who Pays? An Analysis of the Allocation of the Costs of Cancelled Nuclear Plants After Duquesne Light Co. v. Barasch," 50 Ohio St. L. J. 999, 1002 (Fall 1989).

A second approach (the "used and useful" approach) is to include in rate base only electricity generating plant investments that both were prudent when made and become used and useful. Under this approach, the utility regulatory commission reviews the investment decision with the benefit of some hindsight, i.e., the benefit of information that was not available when the investment decision was made. See, e.g., City of Cincinnati v. Public Utilities Commission of Ohio, 620 N.E.2d 826, 829-31 (Ohio 1993) (explaining that used and useful portion of plant is set by stipulation and prudence of that portion is determined based on knowledge at time of investment). The review is necessarily conducted after plant construction is completed and the plant is operating or after plant construction is terminated.

There is significant variation in the details of how various utility regulatory commissions apply the "used and useful" approach test to cancelled-plant investment. See Rodgers and Gray, 13 Hofstra L. Rev. at 452-67. For example, in some cases, when applying the "used and useful" test, utility regulatory commissions both exclude investment that is not used and useful from rate base and deny any recovery of the investment principal. See, e.g., Pacific Power and Light Co. v. Public Service Commission of Wyoming, 677 P.2d 799, 804-09 (Wyo. 1984), cert. den., 469 U.S. 831 (1984) (holding that cancelled nuclear plant is not used and useful property and so plant costs are not recoverable through inclusion in rate base or as operating costs, but stating that costs might be recoverable if plant were reviewed and approved by commission before commencement). By further example, some utility regulatory commissions exclude the investment from rate base but allow amortization, and thus recovery, of the investment principal (but not return on capital). See, e.g., Duquesne Light, 488 U.S. at 313 n.7; Violet v. Federal Energy Regulatory Commission, 800 F.2d 280, 282 (1st Cir. 1986); and NEPCO Municipal Rate Committee, 668 F.2d at 1333 (stating that, while "general rule" is that only "used and useful" investments are included in rate base, FERC may use any method of valuing rate base as long as result is not "unjust or unreasonable" and upholding amortization of costs of cancelled plant and exclusion of such costs from rate base). But see Jersey Central Power & Light Co. v. Federal Energy Regulatory Commission, 810 F.2d 1168, 1175-77 (D.C. Cir. 1987) (explaining that "used and useful" requirement is not constitutionally based and remanding to FERC to determine whether costs of cancelled nuclear plant should be

included in rate base). With regard to cancelled nuclear plants, the majority of utility regulatory commissions have applied the "used and useful" approach, excluded the investment in the plants from rate base, and allowed at least some amortization.[160] Rodgers and Gray, 13 Hofstra L. Rev. at 452-53.

Under a third approach (the "economic used and useful" approach), which is the least frequently used approach, the utility regulatory commission includes, in rate base, plant that was prudent to build and that was initially used and useful but considers whether to continue to allow the plant in rate base in light of ongoing economic changes. Review continues even after the plant is completed and operating. The plant continues to be in the rate base only if the utility regulatory commission finds that the plant continues to be the least cost alternative for the company. See Lesser, 23 Energy L.J. at 359-63.

The "prudent investment," "used and useful," and "economic used and useful" approaches represent the spectrum of approaches used by utility regulatory commissions concerning recovery of capital (and associated return on capital) in electricity generating plants after plant construction is completed or terminated. Depending on the technology and size of an electricity generating plant, design and construction may extend over multiple months or years. Consequently, utility regulatory commissions must also consider the treatment of preconstruction and construction costs during plant construction. Some utility regulatory commissions allow preconstruction and construction costs ("construction work in progress" or "CWIP") to be added periodically to the rate base, during construction until the plant goes into service. See Public Service Co. of New Hampshire, 480 A.2d 20, 23 (N.H. 1984) (explaining that state PUC allowed CWIP in rate base for ongoing nuclear plant construction until prohibited by state legislature). In contrast, some utility regulatory commissions do not allow any preconstruction and construction costs in the rate base until the plant is completed and is in use. The return on capital ("allowance for funds during construction" or "AFUDC") for such costs during construction accrues, and must be carried by the investors, until the plant is in use and becomes used and useful. At that point, the total accrued return on capital during construction is added to the rate base, along with the preconstruction and construction costs of the plant. See Cities for Fair Utility Rates v. Public Utilities Commission of Texas, 924 S.W.2d 933, 935-36 (Tex. 1996); and Kentucky Utilities v. Federal Energy Regulatory Commission, 760 F.2d 1321, 1325 (D.C. Cir. 1985). Some utility commissions have allowed AFUDC to continue to accrue after the plant begins operating and until new rates recovering the cost of the plant actually go into effect. Kentucky Utilities, 760 F.2d at 1326. However, accrual of AFUDC may be suspended while construction is interrupted. See, e.g., Columbus Southern Power Co. v. Public Utilities Commission of Ohio, 620 N.E.2d 835, 842-43 (Ohio 1993).

[160] In a few cases, when the plant investment was excluded from rate base and was amortized, the utility regulatory commission allowed the utility to recover "carrying charges" on the unamortized amounts. If the carrying charges equal the utility's allowed rate of return, this treatment is essentially equivalent to including the plant investment in rate base. Rodgers and Gray, 13 Hofstra L. Rev. at 457 n.105.

Once the rate base is established, the utility regulatory commission must determine a reasonable level for return on capital. The return on capital reflects the anticipated return and risks to the investors providing the capital for the utility and varies depending on the manner in which the capital is obtained (e.g., through the sale to investors of common stock, preferred stock, or long-term debt). Long-term debt may be unsecured (i.e., based on the overall credit of the company issuing the debt), secured (i.e., based both on the overall credit of the company and on a mortgage lien on specified assets of the company), or project-financed (i.e., non-recourse to the company and based on a mortgage on the specific project for which the debt proceeds are used). In general, interest on long-term debt must be paid before dividends on common or preferred stock, and, in the event of bankruptcy, debt holders must be paid off before shareholders. Consequently, long-term debt is considered a less risky form of investment. Preferred stock is considered less risky than common stock because the preferred stock specifies the level of the dividends, payment of such dividends has priority over payment of dividends on common stock, and preferred stock generally outranks common stock in bankruptcy. See Energy Industrial Center Study, Dow Chemical Co. Environmental Research Institute of Michigan, Townsend-Greenspan and Co., Inc., and Cravath, Swaine and Moore, at 432-44 (National Science Foundation June 1975) (discussing the distinctions between debt and equity and the limitations on issuance of debt).

The utility regulatory commission must determine what capital structure (i.e., what proportions of common stock, preferred stock, and long term debt), and what costs of common stock, preferred stock, and long-term debt, to use in determining the utility's return on capital. Generally, utility regulatory commissions use the utility's actual capital structure during the test period and determine the cost of long-term debt and preferred stock by looking at the average, actual cost of existing debt and preferred stock for the test period. The cost of common stock is generally determined by evaluating the return currently required by prospective purchasers of common stock, and various methodologies are used to estimate currently required return. However, some utility regulatory commissions adjust the capital structure to reflect the parent company's capital structure and cost of capital, rather than the structure and costs of the subsidiary utility. See, e.g., General Telephone Co. of Southwest v. Corporation Commission, 652 P.2d 1200, 1205-6 (N.M. 1982). Further, utility regulatory commissions sometimes assume a hypothetical "optimal" (i.e., least cost) capital structure for the utility and determine the costs of common stock, preferred stock, and long-term debt based on that capital structure. See, e.g., Zia Natural Gas Co., 998 P.2d 564, 567-68 (N.M. 2000); Northern Carolina Utilities v. FERC, 42 F.3d 659, 663-64 (D.C. Cir. 1994); and Southern Bell Telephone Co v. Louisiana Public Service Commission, 118 So.2d 372, 380-82 (La. 1960).

In addition to covering return on capital, cost-based rates cover return of capital (i.e., depreciation or amortization of the utility's capital investments). The utility regulatory

commission must determine the number of years over which capital investments are depreciated or amortized for purposes of setting rates.

*Costs related to operation.*

Cost-based rates also cover the utility's operating costs. Operating costs include operation and maintenance (e.g., labor, maintenance materials, administrative support, consumable supplies, and waste disposal), fuel and purchased power, and taxes. Coverage of these costs, of course, may affect investors' return on capital since these costs generally must be paid before any return on equity is actually realized. As with return on capital, utility regulatory commissions generally use actual costs during the test period as a starting point for determining the operating costs to be included in the rates. Test period operating costs may be adjusted in order to ensure that they are representative of future operations. These costs may also be reviewed to determine whether they are reasonable and reasonably related to electric service and may be disallowed if they are not. Generally, operating costs must be disallowed based on evidence of insufficient relationship to electric service or of inefficiency, improvidence, or negligence on the part of the utility, rather than simply on the utility regulatory commission's substitution of its own judgment for that of the company management. See, e.g., Indiana Gas Co. Inc. v. Office of Utility Consumer Counselor, 675 N.E.2d 739, 744 (Ind. Ct. App. 1997). See also Cleveland Electric Illuminating Co., 99 PUR4th 407, 445, 1989 WL 418554 (PUCO Jan. 31, 1989), cause dismissed, Concerned Citizens of Lake County. v. Public Utility Commission of Ohio, 545 N.E.2d 899 (Ohio 1989) (explaining that presumption of reasonableness of operating costs is necessary to limit issues in order to make state PUC review process workable); and Robert L. Swartwout, "Current Utility Regulatory Practice From a Historical Perspective", 32 Nat. Resources J. 289, 327-28 (1992) (stating that prudence review is conducted after a company management decision is made in order to avoid substituting commission judgment for management decision-making, but that current practice is to put the burden of proof of prudence on the utility once a prudence issue is raised).

Rates are not constantly updated, but generally stay in effect until the utility requests, and is allowed to charge, new rates or until the utility regulatory commission initiates, and completes, a review of the existing rates. In some jurisdictions, rates requested by the utility company are suspended for a period of time, after which they may be charged subject to review and refund. In other jurisdictions, requested rates cannot go in effect at all until after regulatory review is completed. Moreover, whether initiated by the utility or the utility regulatory commission, the ratemaking process takes time to complete, and the test-period cost data on which final rates are based may become outdated in the meantime. In addition, in some jurisdictions, limitations exist on how frequently rate-increase requests may be filed. As a result, rates may stay in effect for significant periods of time, and there may be a significant lag between changes in operating costs (or cost of

capital) and changes in rates to reflect such changes in costs. The degree of regulatory lag is reduced to the extent that rate changes are allowed to go into effect subject to refund.

In order to reduce the effect of regulatory lag and achieve a closer match of revenues and costs, utility regulatory commissions often allow certain operating costs (primarily fuel costs and purchased power costs) to be included in rates through an adjustment clause, i.e., a formula that reflects ongoing changes in these costs, rather than at a fixed level based on test period costs. There are various ways to design a fuel or purchased power adjustment clause. See Public Service Co. of New Hampshire v. Federal Energy Regulatory Commission, 600 F.2d 944, 947-49 (D.C. Cir. 1979), cert. den., 444 U.S. 990 (1979) (describing "cost of service" fuel adjustment clause, whose purpose is recovery of actual fuel costs, and "fixed rate" fuel adjustment clause, which does not necessarily reflect accurately actual fuel costs). Under one possible approach, the difference in fuel or purchased power costs for a given future period (e.g., the next quarter) from a baseline level already reflected in the general rates is paid by each customer as an estimated per-kilowatthour charge calculated using recent costs and projected kilowatthours of electricity sales. In addition, the customer's per-kilowatthour charge reflects an adjustment to correct for any difference between the recent and actual costs for the immediately prior period (e.g., the prior quarter) and any difference between projected and actual electricity sales for that period. In some cases, a utility regulatory commission may expand the use of adjustment clauses to encompass the entire cost of service so that the entire rate is expressed as a formula and varies with changes in elements of the cost of service beyond simply fuel or purchased power costs. See Public Utilities Commission of California v. Federal Energy Regulatory Commission, 254 F.3d 250, 254 (D.C. Cir. 2001).

### 7.2. Effect on allocation of electricity generation investment risk.

What follows is a qualitative analysis of the effect of the traditional regulatory system on the allocation of the risk of investment in new electricity generating projects (such as new IGCC plants).[161] For purposes of this qualitative analysis, it is useful to subcategorize investment risk into construction risk, operating risk, and market risk. "Construction risk" is defined as the risk that the project construction will not be completed. Plant cancellation may result, for example, from problems with new technology or design, cost overruns, or declines in demand forecasts. "Construction risk" is also defined to include the risk that, if completed, the plant construction will not be within scheduling or cost targets. "Operating risk" is defined as the risk that the completed project will not achieve

[161] The discussion of risk of investment in, and recovery of project costs of, new IGCC plants applies to all three categories of IGCC plants discussed in Sections 3 and 6 above: i.e., new IGCC plants located on greenfield sites; new IGCC plants located on the sites of, and replacing (repowering), existing pulverized coal plants; and new gasification islands and other equipment added to, and refueling, existing natural gas combined cycle electricity generation equipment.

long-term operational benchmarks, e.g., a minimum level of plant availability or maximum level of generation when the plant is available. Operating problems may result, for example, from problems with new technology or design or from poor operation and maintenance. Both construction and operating risk reflect, at least in part, the technology risk of the type of plant involved and may result in the need to increase electricity generation at, or purchase of electricity from, other sources of electricity in order to meet demand. “Market risk” is defined as the risk that the electricity generated by the operating plant will not be sold at prices that cover capital and operating costs of the plant. The inability to cover costs may result from a reduction in demand or market price or increases in operating costs such as fuel.

7.21. Construction and operating risk.

The inability to complete or operate a new electricity generating plant threatens the recovery of capital investment in the plant and associated return on capital. Such recovery is also threatened to some extent if plant completion is not within scheduling or cost targets. The allocation of construction and operating risk is particularly important for new IGCC plants because they use a capital-intensive technology with which there is relatively limited commercial-scale experience.

*Risk allocation when plant is owned by utility.*

When the new plant is owned by a company subject to traditional utility regulation, the allocation of construction and operating risk associated with the plant depends largely on the utility regulatory commission’s approach to setting, for purposes of cost-based ratemaking, the rate base used in determining return of and on capital. As discussed above, utility regulatory commissions use various approaches in determining rate base.

Under the “prudent investment” approach of including, in rate base, plant investment that is prudent when made regardless of whether the plant is ultimately completed and used, investors bear the risk that utility regulatory commission may determine that the initial decision to invest the capital involved (or a subsequent decision concerning the investment) was imprudent. Ratepayers bear the risk that the plant, which was prudent to construct at the time of the initial and subsequent investment decisions, may not be completed (e.g., due to factors arising after such decisions were made) or, even if prudently completed, may not meet long-term operational benchmarks. Ratepayers also bear the risk of cost overruns where a plant that was prudent to construct at the time of the initial investment and is prudently completed turns out to cost more than originally projected. Ratepayers similarly bear the risk of higher costs for substitute power if, as a result of prudent decisions, such plant takes longer to complete than scheduled. The timing of the utility regulatory commission’s prudence review relative to the timing of the investment determines when risk is put on ratepayers. Generally, the review -- and thus the imposition of risk on ratepayers -- occurs after plant construction is completed or terminated.

To the extent that the utility regulatory commission allows preconstruction and construction costs for prudent projects to be included (as construction work in progress or CWIP) in the rate base before plant completion, there is further allocation of construction and operating risk to ratepayers and that imposition of risk on ratepayers occurs sooner. This is because investors' recovery of construction costs from ratepayers begins earlier and the investors' need for construction loans is reduced. The earlier recovery of cost of capital during construction (which may span two or more years in the case of large, technologically complex plant like an IGCC plant) reduces the accrued cost of capital (in the form of allowance for funds during construction or AFUDC) added to the rate base.

In contrast, under the "used and useful" approach of including in rate base only electricity generating plant investments that both are prudent when made and are actually used and useful, the investor bears more construction and operating risk, than under the "prudent investment" approach. Under the "used and useful" approach, investors bear the risk of an imprudence finding based on conditions when investment decisions were made, the risk that factors arising after those decisions may make the plant investment no longer prudent, and the risk that the completed plant will not operate properly. However, even under this approach, these risks are shared to some extent with ratepayers to the extent the utility is allowed to amortize plant investment that is excluded from rate base. Application of the "used and useful" approach also generally means that investors cannot begin recovering construction costs until after plant completion. Because plant under construction is not yet used and useful, construction work in progress is often not allowed in rate base under this approach. In some jurisdictions, exceptions exist, e.g., for construction of emission controls, but the revenue from including such construction work in progress in the rate base may have to be refunded to ratepayers if the plant is not completed. Ratepayers still bear the risk of cost overruns if the plant was prudently completed but costs more than projected, if the increased costs are found to be reasonable. Ratepayers similarly bear the risk of higher costs for substitute power if completion of such plant was prudently delayed.

Some utility regulatory commissions have explicitly recognized the resulting increased risk to investors under the "used and useful" approach and have therefore allowed companies a higher return on common equity than in the absence of such risk. This higher return is supposed to compensate investors for the enhanced risk that they will be required to write off investments, e.g., in electricity generating projects that are cancelled or that never operate properly.

Under the "economic used and useful" approach, the utility regulatory commission considers on an ongoing basis whether to continue allowing, in the rate base, plant that was prudent to build and that was initially used and useful. Under this approach, plant continues to be allowed in the rate base only if the utility regulatory commission finds that the plant continues to be the least cost alternative for the company. This approach provides the utility regulatory commission with additional, ongoing opportunities to review investment decisions and puts additional risk on the investors. Investors, not

ratepayers, bear the risk that more economic alternatives become available after the plant is prudently constructed and is initially used and useful.

Under the "prudent investment" approach, "used and useful" approach, or "economic used and useful" approach, other entities may assume some of the construction or operating risk. In particular, the engineering, procurement, and construction (EPC) contractor may be willing to guarantee plant completion (e.g., in terms of time, availability schedule, and total cost), supported by underlying warranties that equipment vendors may be willing to provide for specified periods of time for particular equipment and parts. However, it should be noted that the EPC contractor's guarantee of plant completion addresses primarily construction risk, rather than operating risk. The guarantee will likely cover risk up to the point of plant completion and will be satisfied as soon as specific performance tests (e.g., operation at a specified load over a specified period of time) are passed. Moreover, while the underlying equipment warranties covering defects in manufacture may extend over a longer period of time than the plant-completion guarantee, the warranties will likely expire after a relatively limited period of time. Neither the guarantee nor the warranties will likely cover long-term operation of the plant.

In addition, the scope of liability under the guarantee and the warranties is likely to be limited. In particular, the guarantee is likely to be in the form of liquidated damages, and the warranties are likely to be limited to equipment repair or replacement (possibly with an upper limit in the form of liquidated damages). Neither the guarantee nor the warranties are likely to cover fully the replacement energy costs incurred because the plant is not completed or not operating properly.

*Risk allocation where utility has power purchase contract with new plant.*

If a utility does not attempt to construct and own a new plant but rather has a power purchase contract with a new plant that another company undertakes to construct and own, the allocation of construction and operating risk is affected by the terms of the power purchase contract and the regulatory approach taken by the utility regulatory commission concerning pass-through of the purchased power costs under the contract. Power purchase contracts (e.g., contracts for purchase of electricity from qualifying facilities under the Public Utility Regulatory Policy Act (PURPA), 16 U.S.C. 823a, et. seq.) may require payment for capacity and energy only to the extent the plant actually operates to make capacity and electricity available. In that case, the plant's investors (not the purchasing company's investors or ratepayers) bear the construction and operating risk. However, to the extent that a power purchase contract requires some capacity payment regardless of whether the plant actually is completed and operates, the plant's investors share the construction and operating risk with the purchasing utility. The allocation of the risk borne by the purchasing utility, between the utility's investors and ratepayers, depends on the approach taken by the utility regulatory commission with jurisdiction over the utility's pass-through of purchased power costs. The allocation of

such risk is affected by the same factors (other than the factor related to capital structure) that are discussed in Section 7.22 below concerning the allocation of market risk.

7.22. Market risk.

*Risk allocation when plant is owned by utility.*

When the new electricity generating plant is owned or operated by a company subject to traditional utility regulation, the allocation of market risk depends on the ratemaking process and not on market forces because the regulated company is a monopoly with captive customers. In particular, once the utility regulatory commission has determined the extent to which the investment in plant is included in the company's rate base, the allocation of market risk depends generally on: how the utility regulatory commission uses test period costs to set rates; how the commission sets rate of return; how expeditious the commission is in its rate determinations; and whether the commission allows pass-through of costs (e.g., fuel or purchased power costs) through adjustment clauses.

First, utility regulatory commissions generally require that rates be based on actual test period costs, with some adjustments. As discussed above, utility regulatory commissions have the authority to disallow test period costs found to be insufficiently related to electric service or to be imprudent, and this increases investors' risk that revenues will not cover all costs, with the result that ability to pay interest on debt may be threatened and earned return on equity may be eroded. In addition, utility regulatory commissions may make adjustments of actual test period costs to make costs representative of normal operation for the period or to reflect anticipated future changes in operation. The adjustment of test period costs, particularly for future changes in costs, tends to reduce the investors' risk that revenues will not reflect cost increases and so will erode return on equity. Some utility regulatory commissions take an alternative approach to addressing future changes by allowing use of a forward-looking test period based on projected costs and sales. In addition, during periods of increasing costs, utility regulatory commissions have sometimes included in allowed rate of return an "attrition allowance" in order to offset the potential erosion of earned return in the future. See, e.g., Office of Consumers' Counsel, v. Public Utilities Commission of Ohio, 413 N.E.2d 799, 802-5 (Ohio 1980). The latter approach also tends to reduce investors' market risk.

Second, utility regulatory commissions must determine, for purposes of setting rates, what capital structure, and what capital-cost determination methodologies, to use in setting the utility's return on capital. As discussed above, utility regulatory commissions generally use the utility's actual capital structure in the test period, calculate the actual embedded cost of debt and preferred stock, and use various methodologies to determine the return on common equity. However, some utility regulatory commissions assume -- and determine cost of capital and set the return on capital based on -- a hypothetical "optimal" capital structure for the utility, rather than the utility's actual capital structure.

That approach increases the market risk to investors in that the utility regulatory commission may review both the investment decision itself and the means by which the utility finances the investment. A determination that the utility did not use the optimal capital structure may effectively result in disallowance of a portion of the utility's cost of capital. In addition, utility regulatory commissions generally determine the cost of capital, and set the return on capital, after the investment has been made and put in rate base and retain the right to periodically review and change the return on capital (and, in particular, the return on common equity). This increases the risk to investors that anticipated return may not be realized throughout the life of the investment.

Third, the longer the lag between the time when a rate case is initiated (e.g., when a company requests a rate increase based on test-period cost data) and the time when the utility regulatory commission renders a rate determination and allows new rates to go into effect, the greater the risk borne by investors that revenues will not properly reflect cost changes and that the ability to pay interest on debt and return on equity will be eroded. As discussed above, regulatory lag and resulting risk to investors are reduced to the extent the utility regulatory commission is authorized to allow rates requested by the company to go into effect, subject to refund, before the final rate determination. Obviously, depending on whether costs are generally rising or falling, the delay may actually turn out be advantageous or disadvantageous to investors during a particular period. However, a ratemaking system that tends to result in a relatively close matching of revenues and costs (including return on equity) provides a relatively stable return on equity and tends to reduce investors' risk.

Fourth, in order to mitigate the effect of regulatory lag, many utility regulatory commissions allow the significant, and potentially volatile, costs of fuel to be passed through to ratepayers through adjustment clauses. A fuel adjustment clause establishes a formula under which the fuel-charge portion of the rate is recalculated periodically (e.g., for each upcoming quarter) to reflect recent levels of fuel costs (e.g., fuel costs during the prior quarter) and projected electricity sales. The formula also has a component that takes account of any difference between the dollar amount of fuel costs recovered through the adjustment clause during the prior period (e.g., prior quarter) and that period's actual dollar amount of fuel costs. In that way, over time, the company generally recovers no more, and no less, than its actual fuel costs. This is important because fuel costs may comprise as much as 40 percent of a utility's total cost of service (and, e.g., 20 to 25 percent of the cost of energy from a coal-fired plant). Coordinated to occur with each periodic adjustment (or after several adjustments) are expedited review proceedings conducted by the utility regulatory commission to ensure that only reasonable, properly calculated costs are passed through. By reducing the risk to investors that volatility of fuel costs will erode the return on common equity, use of adjustment clauses puts the risk of fuel-cost volatility on ratepayers.

To the extent purchased power costs (or costs of fuel used to generate purchased power) are passed through an adjustment clause, the risk of volatility of such costs is also put on

ratepayers. Similarly, the use by some utility regulatory commission of adjustment clauses for other types of costs of service, or the entire cost or service, puts the risk of cost changes on ratepayers and reduces investors' market risk.

*Risk allocation when utility has power purchase contract with new plant.*

To the extent that a company purchases electricity from another company rather than constructing electricity generating plant, the allocation of market risk is affected by the terms of the power purchase contract and the approach taken by the utility regulatory commission concerning recovery of costs under the contract. The power purchase contract may set the power purchase price using a formula that recalculates the price periodically to reflect changes in costs (e.g., annual changes in fuel costs). Where the power purchase price is adjustable, market risk is imposed on the purchasing utility, which bears increases in the plant owner's costs; where the power purchase price is fixed, market risk is imposed on the plant owner, who cannot pass through cost increases to the purchasing utility. As between investors and ratepayers of the purchasing utility, the allocation of market risk is affected by the factors (other than the capital-structure-related factor) discussed in this Section 7.22 with regard to a utility that owns a new plant.